TRANSMISSIVITY AND PETROPHYSICAL PROPERTIES OF DEEP WATER AREA, NIGER DELTA, NIGERIA

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Abstract: The quality of the reservoirs in terms of porosity, permeability and transmissivity decreases down the depth. Therefore, it can be concluded that the hydrocarbon potential and productivity of the reservoir sands can be classified in decreasing order of arrangement as A, B and C. The reservoir A in well Bonn 007, 009, 013, 015, 017 and 019 is the best in terms of hydrocarbon production and hydrocarbon in such wells can easily migrate to the wellbore as compared to other two reservoirs.

Key Words: Reservoirs, Niger Delta, Transmissivity, Hydrocarbon.

1. INTRODUCTION:

Reyment (1960 & 1965) described the stratigraphy of the different depositional basins in Nigeria and created a large number of lithostratigraphic and biostratigraphic divisions. Murat (1970) presented a paleogeographic description of the Cretaceous and Lower Tertiary in Southern Nigeria based on major depositional cycles resulting from three main tectonic episodes. Carter, Barber and Tait (1963), Jones (1964), Adeleye and Dessavagie (1970), Kogbe (1972), Adegoke et al., (1978), Petters (1978), Alix (1983), Popoff et al.(1983), Whiteman (1982), Benkhelil and Guiraud (1980), Benkhelil (1982 & 1986), Allen (1963, 1964, 1965 & 1980) and others have described the stratigraphy and paleogeography of individual or part of different sedimentary basins in the country.

The Niger Delta is a prograding depositional complex within the Cenozoic formation of Southern Nigeria. It is situated between longitudes 3^0 and 9^0 E and latitudes 4^0 and 6^0 N (Fig. 1). It is a prolific oil province where one petroleum system, the Tertiary Niger Delta (Akata-Agbada) petroleum system has been identified and is one of the largest in the West African sub-region (Fig. 2). Reservoirs in the Niger-Delta exhibit a wide range of complexities in their sedimentological and petrophysical characteristics.

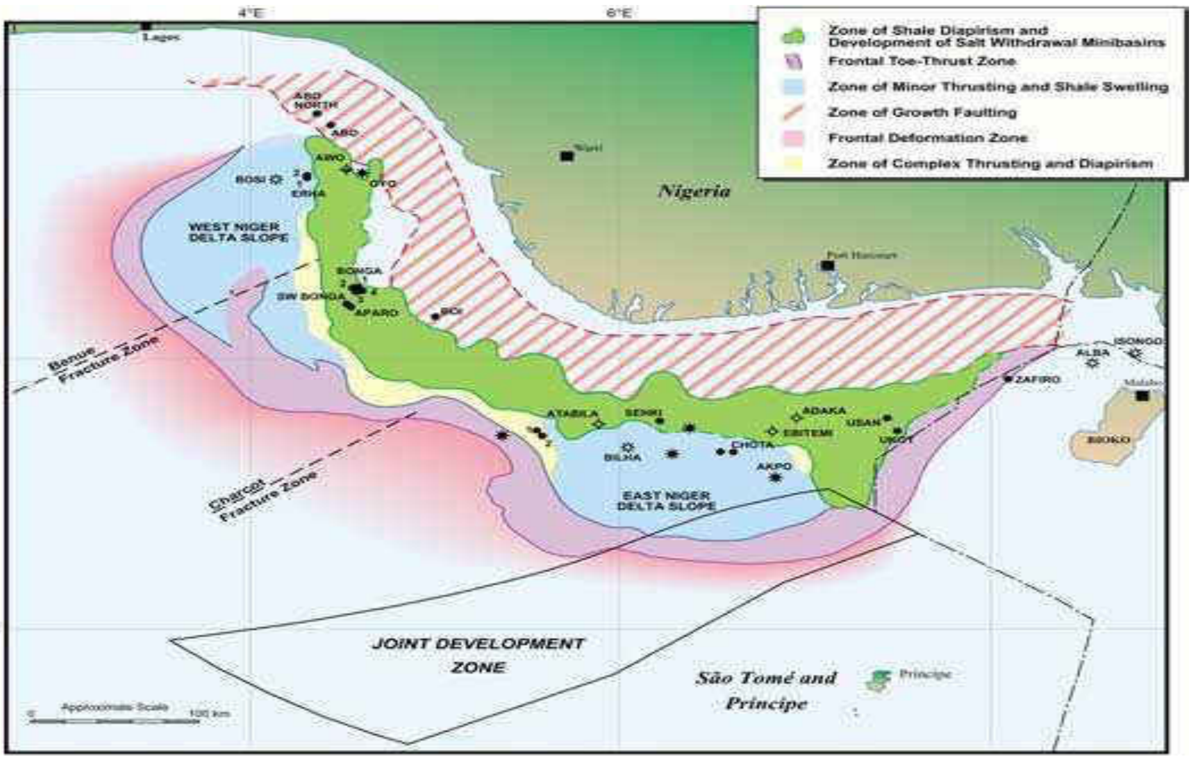

Fig. 1: Location map of Niger Delta (Study Area).

2. LOCATION OF STUDY:

The field under study is pseudo-named "X'' field in accordance with the confidentiality agreement. The field is located in the offshore Niger Delta (Fig. 1), but the co-ordinates of the location of this field were concealed due to proprietary reasons.

3. OBJECTIVES OF STUDY:

This research is aimed at evaluating the reservoir potential of X-field with limitation to the available data primarily to achieve the following objectives:

- ✓ To identify the various sand bodies and correlate them across the field.
- ✓ To identify and quantify hydrocarbons in the reservoirs sand bodies.
- ✓ To determine the petrophysical characteristics of sand bodies.
- ✓ To estimate and compare porosity, permeability and hydrocarbon distribution

4. METHODOLOGY:

DESCRIPTION OF WIRELINE LOGS USED

The different logs used for the research work are Gamma ray log, Resistivity logs, Compensated Bulk Density log and Porosity log. The wireline logs were used in the interpretation and calculation of the various functions and parameters of the reservoir sands as described below.

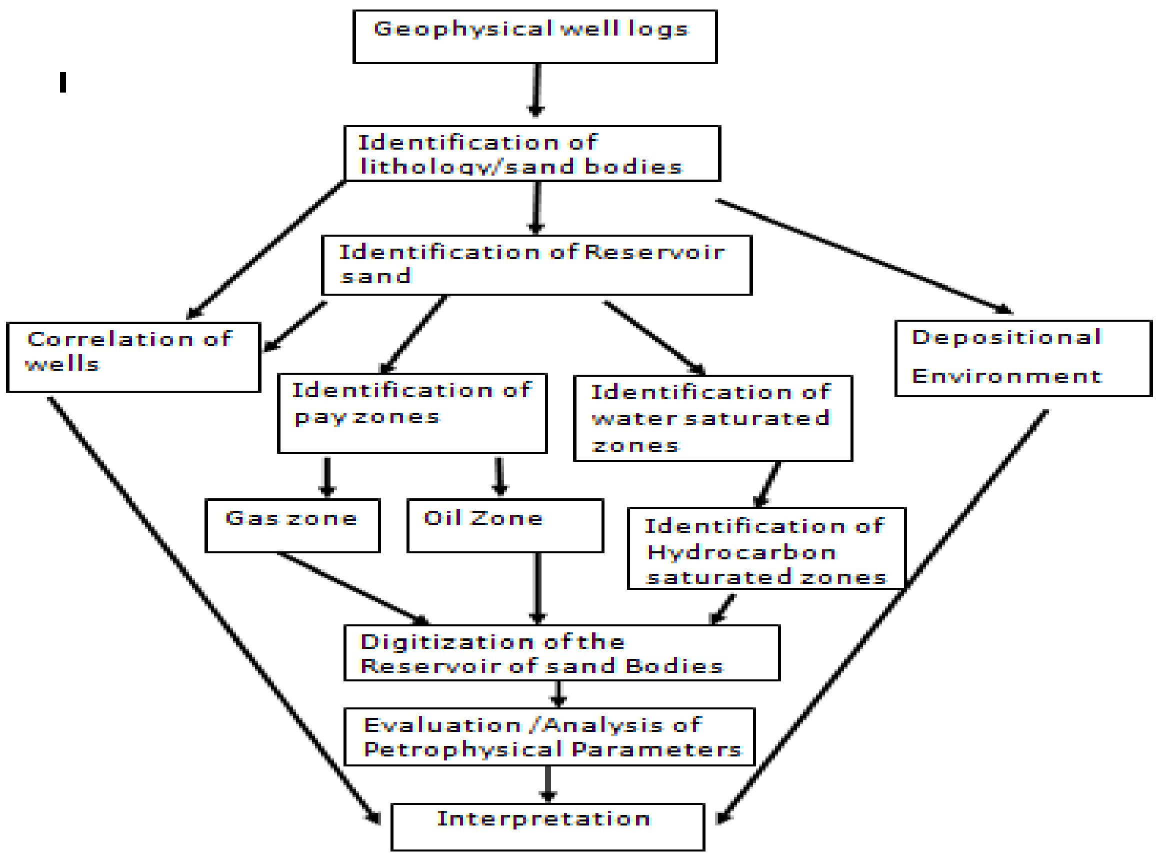

Figure 2: Methodology Flow chart.

(a) GAMMA RAY LOGS

Shale usually contains small quantity of radioactive elements such as uranium (U) potassium (k) and thorium (TH). This produces gamma ray radiation from which the source can be detected by spectrometry. The log thus, detects shale horizon and can provide an estimate of the clay content and other sedimentary rocks. Amongst, the sediments, shales have by far the strongest radiation. That is why the log is called "Shale Log".

(b) RESISTIVITY LOGS

Resistivity is the specific resistance of a material to the flow of current (inverse of conductivity). The resistivity of a formation depends on the electrical conductivity of the rock material within the formation, the nature of formation water

(fresh or salt water), other fluids like oil or gas contained in it, the porosity and tortuosity of the formation.

Generally, resistivity is high in porous rocks containing oil, gas or even fresh water because these fluids are insulators. Oil and gas produce much higher kicks on the resistivity log and gas higher than that of oil kicks. Porous rocks containing salt water (electrolyte) have low resistivity because it is conductive. Clay produces no kick on the resistivity curve; the portion on the log with no resistivity kick is thus definitely shale and this is known as the shale line.

(c) DENSITY LOGS

Density log makes used of artificial gamma ray from a radioactive source (e.g. “^{60}Co and ^{137}Cs) as a continuous record of a formation bulk density. Bulk density is overall density of a rock including solid matrix and fluid enclosed in the pores. Gamma photons collide elastically with electrons and are reduced in energy (Compton Scattering). The number of collisions over any particular interval of time depends upon the abundance of electrons present (electron density index) which in turns is the function of the formation.

Density is thus estimated by measuring the proportion of gamma radiation Compton Scattering. A deflection of bulk density log to the right indicates high density compacted formation and deflections to the left indicates low-density under-compacted formations. In hydrocarbon bearing reservoir sand, the bulk density reading is usually higher in oil bearing zones and lower in gas bearing zones. Density is measured in grams per cubic centimeter (g/cm^3).

The compensated bulk density log has been used in this research to:

- ✓ Determine the porosity values of sand bodies.
- ✓ Draw the bed boundaries due to its good resolution.
- ✓ Determine permeability from porosity and water saturation values.
- ✓ Determine formation factor.

(d) **IRREDUCIBLE WATER SATURATION (S_{wirr})**

When a zone is at irreducible water saturation (S_{wirr}) ,the water saturation in the uninvaded zone (S_w) will not move because it is held on grains by capillary pressure.

For most reservoir rock, irreducible water saturation ranges from less than 10% to more than 5O% (Schlumberger, 1985 & 1989)

Table 1: Qualitative Description of Porosity Values (After Dresser Atlas, 1982).

PERCENTAGE (%)	QUALITATIVE EVALUATION
0 -5	Negligible
5-10	Poor
10 -15	Fair
15 -20	Good
20 -30	Very good
Over 30	Excellent

(e) **PERMEABILITY (K)**

Permeability is a measure of the ease with which a formation permits a fluid to flow through it. To be permeable a rock must have interconnected porosity. Greater porosity usually corresponds to greater permeability but this is not always in the case. The ability of a rock to transmit a single fluid when it is completely saturated with that fluid is called absolute permeability while effective permeability refers to the ability of the rock to transmitted one fluid in the presence of another fluid when the two fluids are immiscible.

5. RESULTS AND INTERPRETATION:

CORRELATION OF THE RESERVOIR SANDS

The correlation was carried out based on the positions of the sands and shales on the well logs across the wells

The gamma ray (GR) logs were the main logs used because they exhibit patterns that are easier to recognize and correlate from well to well. The resistivity logs were then used to cross-check the correlation because individual shale beds exhibit distinctive resistivity characteristics across the wells.

From the reservoir analysis, three reservoirs (A, B, C,) were observed and of which only reservoir A is correctable across the six well. This implies that reservoir A is genetically equivalent laterally (in the same depositional environment). But, the displacement of this reservoir in depth is probably as a result of synthetic fault.

PETROPHYSICAL RESULTS AND INTERPRETATION

Total of three hydrocarbon reservoirs were identified and evaluated. Reservoir A cuts across the six wells. (Bonn 007, Bonn 009, Bonn 013, Bonn 015, Bonn 017 and Bonn 019)

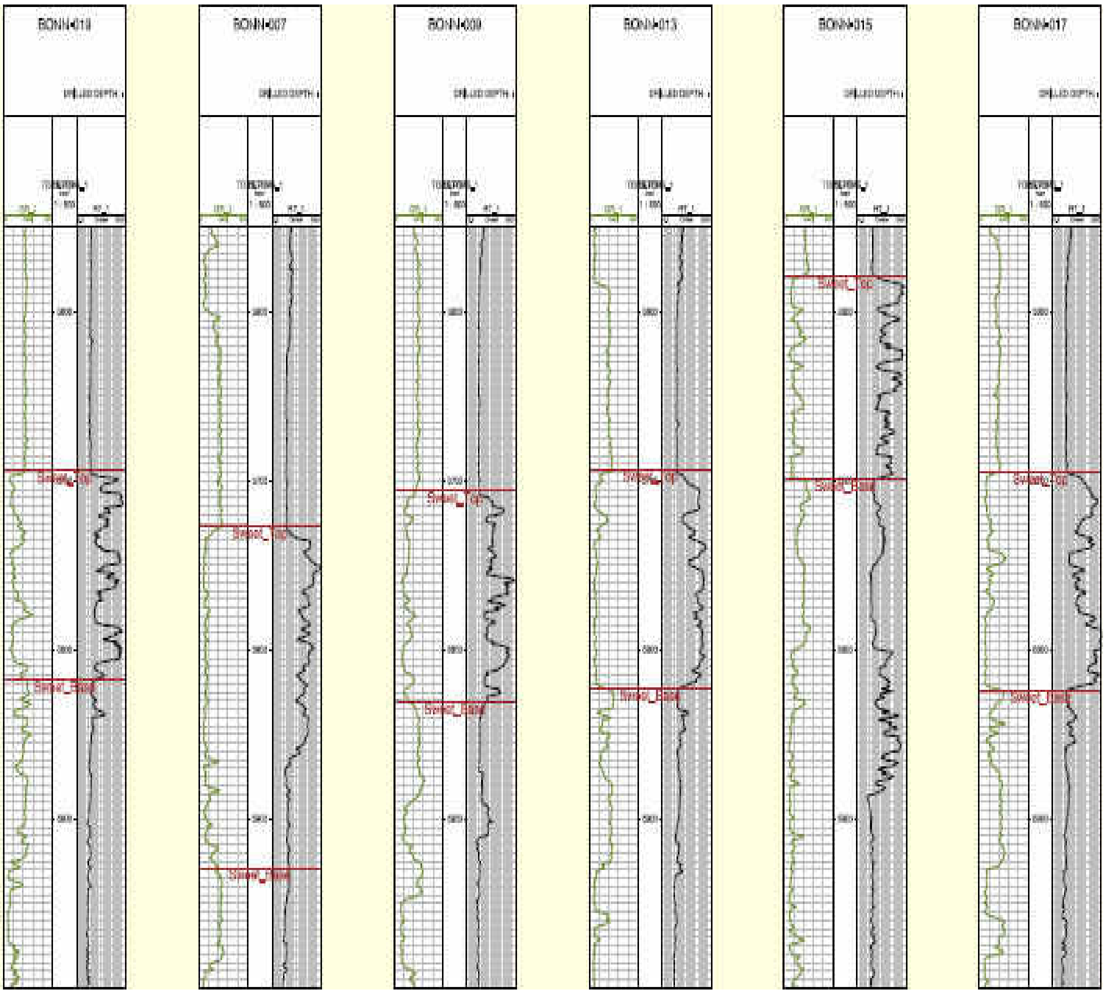

Figure 3; The studied wells showing reservoir intervals

Reservoir B cuts across the four wells (Bonn 007, Bonn 013 and Bonn 015 Bonn 017). Reservoir C cuts across the three wells (Bonn 009, Bonn 015 and Bonn 019).

The following petrophysical parameters were quantitatively analyzed for the reservoirs: Volume of Shale (V_{sh}), Porosity (ø), formation factor (F), Irreducible water saturation (S_{wirr}), permeability (K), water saturation (S_w), Hydrocarbon saturation (S_h) and Bulk volume water (BVW). The results are summarized in Table 5 and 6.

CHARACTERISTICS OF RESERVOIRS OF WELL BONN 007

There are two hydrocarbon reservoirs found in the well BONN 007. These are reservoirs A and B

In reservoir A, it occurs at interval of 5727 – 5931ft (1746-1808m) and has a gross (G) and net (N) thickness of sand, 204ft (62.2m) and 176.5ft (53.8m) respectively, with N/G ratio of 0.87; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 28% and 2092md respectively. Its transmissivity is 426850mdft . Therefore, the reservoir A has very good porosity and excellent permeability.

CHARACTERISTICS OF RESERVOIRS OF WELL BONN 009

Both reservoirs A and C have hydrocarbon. In reservoir A, it is found at the interval of 5706 – 5831ft (1739-1777m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 100.5ft (30.6m) respectively, with N/G ratio of 0.80; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%, porosity ((ø) and permeability (K) of 22% and 432md respectively while its transmissivity is 54000mdft (Table 4). Therefore, the reservoir has good porosity and very good permeability.

In reservoir C, the hydrocarbon occurs at interval of 8376 – 8488ft (2553-2587m) and has a gross (G) and net (N) thickness of sand, 112ft (34.1m) and 90ft (27.4m) respectively, with N/G ratio of 0.19; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø), permeability (K) and transmissivity are 17%, 79.9md and 8949mdft respectively (Table 4). The reservoir C therefore, has both good porosity and permeability.

The formation bulk volume water values calculated are nearly constant and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water – free hydrocarbon. The transmissivity in reservoir A is higher than of C. This means that lateral migration of hydrocarbon from reservoir to a well bore will be faster in A than C.

CHARACTERISTICS OF RESERVIORS OF WELL BONN 015

There are three hydrocarbon reservoirs (A, B and C) observed in well BONN 015.

Reservoir A occurs at the interval of 5579ft – 5699ft (1700-1737m) and has a gross (G) and net (N) thickness of sand, 120ft (36.5m) and 109.5ft (33.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 22% and 424.6md respectively. Its transmissivity is 50952mdft. Therefore, reservoir A has both very good porosity and permeability.

Reservoir B occurs at the interval of 5797 – 5887ft (1767-1794m) and has a gross (G) and net (N) thickness of sand, 90ft (27.4m) and 81.5ft (24.8m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%, porosity (ø) and permeability (K) of 18% and 175.5md respectively. Its transmissivity is 15795mdft (Table 5). Therefore, the reservoir has good porosity and very good permeability.

CHARACTERISTICS OF RESERVOIRS OF WELL BONN 017

There are two hydrocarbon reservoirs observed in the well BONN 015. These are reservoir A and B.

Reservoir A occurs at the interval of 5695 – 5824ft (1736-1775m) and has a gross (G) and net (N) thickness of sand, 129ft (39.3m) and 118.5ft (36.1m) respectively, with N/G ratio of 0.9; water saturation (S_w) of

19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 32% and 5024md while its transmissivity is 648148mdft. Therefore, the reservoir has both excellent porosity and permeability.

Reservoir B occurs at the interval of 8370 – 8478ft (2551-2584m) and has a gross (G) and net (N) thickness of sand, 108ft (32.9m) and 97.4ft (29.7m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 30% and 1975md respectively. Its transmissivity is 213311mdft. Therefore, the reservoir has both excellent porosity and permeability.

The formation bulk volume water values calculated are nearly constant (Table 5) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. Transmissivity in A is higher than B which means that lateral migration of hydrocarbon to the well bore will be faster in reservoir A than in B.

CHARACTERISTICS OF RESERVOIRS OF WELL BONN 019

There are two hydrocarbon reservoirs found in the well BONN 019. These are reservoirs A and

Reservoir A occurs at the interval of 5693 – 5813ft (1735-1772m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 110ft (33.5m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 20% and hydrocarbon saturation (S_h) of 80%, porosity (ø) and permeability (K) of 18% and 116.2md respectively. Its transmissivity is 14525mdft. Therefore, reservoir A has both good porosity and permeability.

Reservoir C occurs at the interval of 7350 – 7619ft (2240-2322m) and has a gross (G) and net (N) thickness of sand, 89ft (27.1m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 14% and 22.4md. Its transmissivity is 1993.6mdft. Therefore, reservoir C has fair porosity and moderate permeability.

The formation bulk volume water values calculated are nearly constant and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. The transmissivity in reservoir A is higher than C. This means that the hydrocarbon in reservoir A will flow faster to the well bore as compared to reservoir C.

GENERATING EMPIRICAL RELATIONSHIP BETWEEN DEPTH, POROSITY AND PERMEABILITY

From the petrophysical values, both the porosity and permeability decreases down the depth Therefore, empirical formulas can be generated to show the relationship between (1) depth and porosity, (2) depth and permeability. These formulae can be derived from below:

Since the porosity varies inversely with depth (D) the relationship between porosity (∅) and depth can be written as

$$D \propto \frac{1}{\phi}$$

Let m represents the constant between depth and porosity.

$$\text{Then, } D = \frac{m}{\phi} \quad \text{--(16)}$$

From the graph below, variables of depth (D) and porosity were taken and empirical formula between depth and porosity can be derived in below:

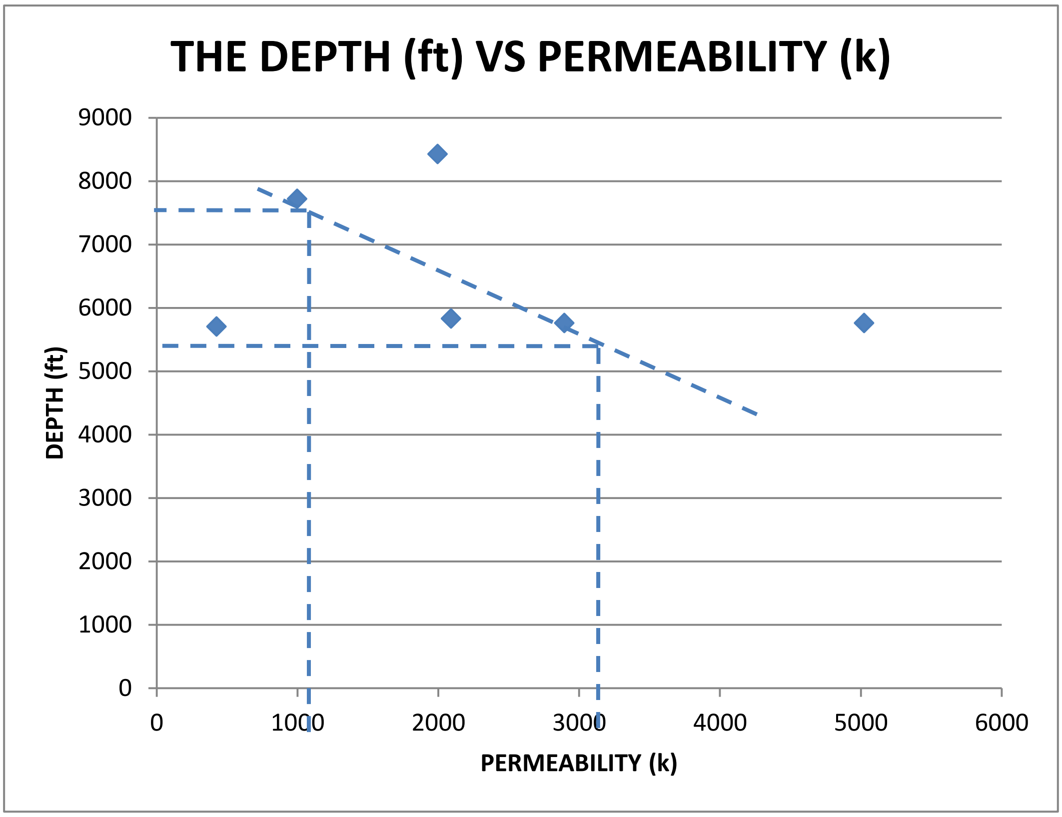

Fig. 4: The graphs showing relationship between depth and permeability.

TABLE 2: RESERVOIR SAND/SHALE PERCENTAGE CALCULATIONS FOR SIX WELLS.

RESERVOIRS	**% SAND**	**% SHALE**
A	86	14
B	63	37
	WELL BONN 009	
RESERVOIRS	**% SAND**	**% SHALE**
A	60	40
C	75	25
	WELL BONN 013	
RESERVOIRS	**% SAND**	**% SHALE**
A	80	20
B	75	25
	WELL BONN 015	
RESERVOIRS	**% SAND**	**% SHALE**
A	50	50
B	80	20
C	85	15
	WELL BONN 017	
RESERVOIRS	**% SAND**	**% SHALE**
A	**75**	**25**
B	**63**	**37**
	WELL BONN 019	
RESERVOIRS	**% SAND**	**% SHALE**
A	60	40
C	75	25

The empirical formula between depth (ft) and permeability is given as:

$D = 3717563.4K^{-1}$, that is approximately as

$D = 3.7 \times 10^6 K^{-1}$ --(28)

Therefore, $K = 3.7 \times 10^6 D^{-1}$ --(29)

Where D= depth (feet) and K = Permeability (md)

Another formula can be derived when feet is converted into metres and can be derived as below:

From equation (25),

N = 1959.54 x 1897. 2

But 1959ft = (1959.5 x 0.3048) metres = 597.3m

Hence, N = 597.3 x 1897.2 = 1133113.3

The empirical formula between depth (m) and permeability (k) can be given as:

$D = 1133113.3\ K^{-1}$, that is approximately as:

$D = 1.1 \times 10^6 K^{-1}$ --(30)

Therefore, $K = 1.1 \times 10^6 D^{-1}$--(31)

The reservoir sand bodies of X-field have three hydrocarbon reservoirs (A, B and C) of which only reservoir A cuts across the six wells.

In reservoir A, both porosity and permeability are excellent while its transmissivity is the highest. The hydrocarbon saturation ranges 86 – 80%.

In reservoir B, both porosity and permeability are very good. The hydrocarbon saturation ranges 86-70% while its transmissivity is the second among the three reservoirs.

Reservoir C has fair porosity and moderate permeability. The hydrocarbon saturation ranges 81-80%. Its transmissivity is the least.

With these petrophysical values, the reservoirs of the study area can be said to be prolific in terms of hydrocarbon production and they will produce water-free hydrocarbon due to the fact that all these reservoirs are homogenous and at irreducible water saturation.

The reservoirs bulk volume water (BVW) values calculated are close to constant, this indicates that the reservoir are homogenous and at irreducible water saturation. Therefore, reservoirs can produce water – free hydrocarbon. When a reservoir is at irreducible water saturation, water saturation (S_w) will not move because it is held on grains by capillary pressure. The petrophysical parameters show a gradual decrease from the top to bottom of the wells, reflecting increase in compaction with depth. The porosity, permeability and transmissivity also followed the same trend

The quality of the reservoirs in terms of porosity, permeability and transmissivity decreases down the depth. Therefore, it can be concluded that the hydrocarbon potential and productivity of the reservoir sands can be classified in decreasing order of arrangement as A, B and C. The reservoir A in well Bonn 007, 009, 013, 015, 017 and 019 is the best in terms of hydrocarbon production and hydrocarbon in such wells can easily migrate to the wellbore as compared to other two reservoirs.

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